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Modeling the Relative GHG Emissions of Conventional and Shale Gas Production

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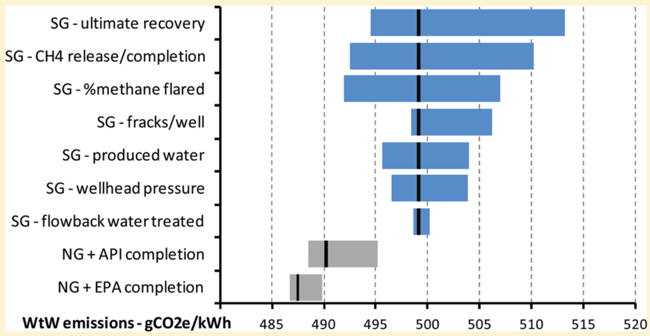
S Supporting Information

ABSTRACT: Recent reports show growing reserves of unconventional gas are available and that there is an appetite from policy makers, industry, and others to better understand the GHG impact of exploiting reserves such as shale gas. There is little publicly available data comparing unconventional and conventional gas production. Existing studies rely on national inventories, but it is not generally possible to separate emissions from unconventional and conventional sources within these totals. Even if unconventional and conventional sites had been listed separately, it would not be possible to eliminate site-specific factors to compare gas production methods on an equal footing. To address this difficulty, the emissions of gas production have instead been modeled. In this way, parameters common to both methods of production can be held constant, while allowing those parameters which differentiate unconventional gas and conventional gas production to vary. The results are placed into the context of power generation, to give a "well-to-wire" (WtW) intensity. It was estimated that shale gas typically has a WtW emissions intensity about 1.8−2.4% higher than conventional gas, arising mainly from higher methane releases in well completion. Even using extreme assumptions, it was found that WtW emissions from shale gas need be no more than 15% higher than conventional gas if flaring or recovery measures are used. In all cases considered, the WtW emissions of shale gas powergen are significantly lower than those of coal.



INTRODUCTION

Tight Gas. A gas well is called "tight" if it requires stimulation before gas production can begin, or if it needs stimulation to maintain production. Tight sands, shale gas, and coal bed methane are all examples of "tight" gas production and are collectively described as "unconventional" gas.

Tight gas production is characterized by low rock permeability. Conventional gas occurs in rocks with a permeability of more than 1000 microdarcy, whereas tight sands have a permeability of 1−100 microdarcy and shale permeability is 1 microdarcy or less.[1] Where the permeability is low, gas can only be collected within a small radius of the well bore. As a result, more or longer wells must be drilled and the rock must be fractured to access the gas.

Unconventional gas drilling differs from conventional in the large amounts of water used for hydraulic fracturing, approximately 2−4 million gallons (7500−15 000 m^3) of water per well.[2] The fluid pumped into the well consists mainly of water and sand (~98%) with various chemicals (flow improvers to keep the sand in suspension, friction reducers, surfactants, corrosion inhibitors, acids, etc.). Much of this water flows back to the surface following fracturing. In addition to these chemicals, flowback water contains salt and other minerals. Some flowback water can be recovered for reuse but, unless there is an opportunity to reinject the water locally, it must be treated before disposal.

There are no systematic differences in gas composition between unconventional and conventional gas reservoirs. Both are equally likely to contain high or low levels of contaminants such as CO_2 or H_2S. Production of water over the life of the well varies considerably among rock formations. Coal bed methane typically produces a lot of water; shale gas is typically quite dry.

Shale Gas. Unconventional gas now makes up about 50% of North American gas production and is predicted to rise to 64% by 2020.[3,4] For the world as a whole, EIA estimates that "adding the identified shale gas resources to other gas resources increases total world technically recoverable gas resources by over 40% to 22 600 trillion cubic feet".[5]

The most significant trend in U.S. natural gas production is the rapid rise in production from shale formations. This is largely attributable to advances in horizontal drilling and well stimulation technologies and improvements in their cost effectiveness.

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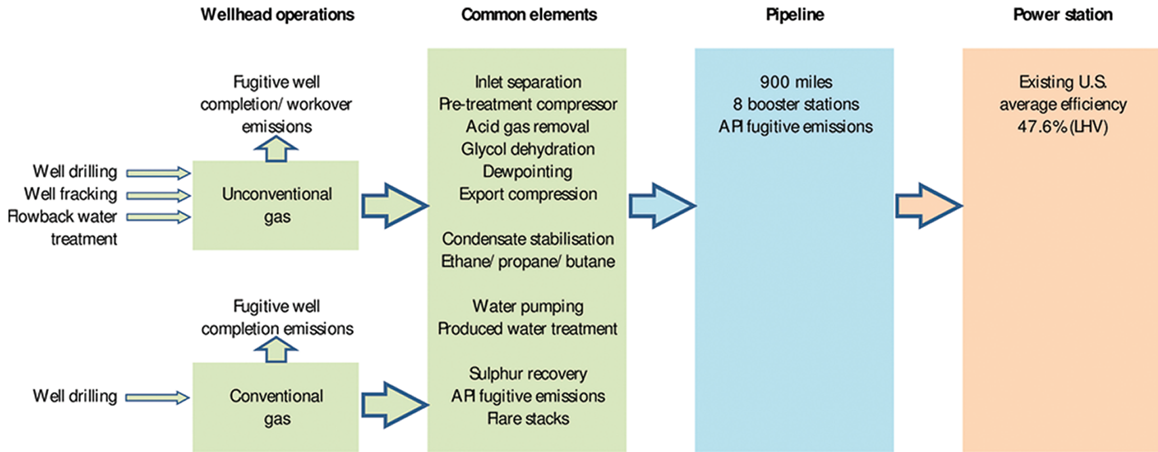

Figure 1. Simplified well-to-wire (WtW) pathway.

METHODOLOGY: COMPARING CONVENTIONAL AND SHALE GAS

Inventory versus Modeling Approach. It is possible to estimate the emissions intensity of the gas industry from the total emissions reported for a territory. For example, Jaramillo[6] estimated the emissions intensity of natural gas powergen using sector emissions data from the 2004 U.S. EPA Inventory Report.[7] At that time, it was not possible to distinguish unconventional gas and conventional gas production within the totals. The EPA's 2011 Inventory Report[8] attempted to separate the two, but the underlying data do not contain enough detail to do this accurately and their results could only be based on estimates.[9] However, even if individual production sites had been listed separately, it would not be possible to eliminate site-specific factors (such as gas composition) to compare unconventional gas and conventional gas production methods on an equal footing.

To overcome these difficulties, the emissions of gas production can be modeled. In this way, those parameters which are common to both methods of production can be held constant, while allowing those parameters which characterize unconventional gas and conventional gas production to vary. Unlike an inventory approach, where data ranges can only be identified for different producers, ranges of uncertainty can be evaluated for individual parameters within the production process.

This modeling work adopted a four-stage approach to understanding the differences between conventional and shale gas production.

First, two generic base cases were defined: conventional gas and shale gas, defined on the basis of typical parameters. The results for conventional gas production provide a simulated, but realistic yardstick against which shale gas production can be judged.

Second, a sensitivity analysis was conducted by varying the production parameters one by one within the likely range of variation at actual production sites. The results show which parameters have most influence on GHG emissions intensity and which are relatively unimportant.

Third, a "worst case" analysis was conducted. Whereas the sensitivity analysis varied one parameter at a time, the worst case analysis looked at the cumulative effect of these changes. The results show how high the GHG emissions might be in the most unfavorable circumstances.

Finally, the relevance of the findings to shale gas production in the U.S. and elsewhere is discussed. The findings are compared against the results of other recent publications.

Scope. Unconventional gas production requires large numbers of wells and those wells may be reworked during the lifetime of the project. Well drilling and completion emissions are potentially significant compared to the total emissions over the lifecycle of a project. Furthermore, the EPA recently increased its estimate of the fugitive emissions from unconventional well completions and workovers. Well completion emissions were therefore also included in the scope.

The following items were included in the analysis:

- CO_2, CH_4, and N_2O emissions associated with combustion of fuels at every stage of the lifecycle, applying 2007 IPCC AR4 factors for 100-year global warming potential. (Some authors have considered 20-year global warming potential factors, but use of these is not widely accepted.)
- Venting, flaring, and fugitive (VFF) emissions from gas production facilities and transport pipelines.
- Lifecycle emissions of imported fuels, e.g., production of diesel fuel and the fuels used for grid-supplied power.
- Emissions from the transport and treatment of produced and flowback water.

The analysis does not include the following:

- Non-GHG environmental impacts.
- Land use change emissions associated with access road and well pad construction (these were assessed but found to make no material contribution to WtW emissions).
- Exploration and appraisal of new gas fields. Relatively few wells (~1%) are drilled in the appraisal phase compared to the total number of producing wells.
- Lifecycle emissions of the chemicals used in fracturing or gas treatment.
- Emissions associated with construction or end-of-life disposal of equipment.

Functional Unit. EIA data for 2009 show that 94% of U.S. coal is used for powergen[10] so, when comparing the life cycles of gas and coal, it is appropriate to consider 1 kWh of electricity to be the functional unit of the life cycle analysis and compare WtW rather than combustion emissions. Gas powergen typically has higher efficiency than coal powergen, which tends to reduce the WtW emissions of gas relative to coal.

Allocation of Emissions to Gas and Coproducts. A gas production project may have multiple coproducts: not only gas, but also condensate, ethane, and LPG. To calculate the emissions intensity, the emissions total must be divided between the sales gas and other coproducts. Allocating emissions in this way removes some of the uncertainty introduced by differences in gas composition at various locations. Condensate and LPG carry a proportionate share of the total emissions so the results remain comparable with locations that produce more or less condensate and LPG.

Emissions were allocated to coproducts in proportion to their energy content. The allocation was the same for conventional and shale gas because the same gas composition was used in both models.

CONSTRUCTION OF THE MODEL

To show the relative importance of gas production emissions in the context of the fuel life cycle, it is assumed that gas is transported by pipeline to a power station and used to generate electricity. The gas lifecycle has been simplified to four steps, as shown in Figure 1: extraction, gas treatment, pipeline transmission, and combustion at power station to generate electricity (excluding transmission losses).

Choice of Model Parameters. Once the gas has been gathered, there are no essential differences in subsequent treatment. This study focused on the parameters that are necessarily different between unconventional and conventional gas in the wells and gathering system.

Extensive data are available for North America, via the U.S. Energy Information Administration (EIA), U.S. Environmental Protection Agency (EPA), and other government and industry bodies. For this reason, the model reflects unconventional gas production in a North American context, but the insights generated can be applied to unconventional gas production elsewhere. Shale gas is the major source of growth in unconventional gas production and therefore the analysis looked mainly to shale gas sources.

Model Gas Composition. Data from the 2011 EPA Inventory Report[8] show that there is no systematic variation in the CO_2 content of conventional and unconventional gas wells. The data show an almost complete overlap, with both types of gas ranging from nearly zero to more than 7%. A single gas composition was therefore used to model both conventional and unconventional production. Data from EIA and EPA reports were used to derive a composition typical of average U.S. gas composition (Supporting Information, S2.1).

Gas Treatment: Common Elements. Gas treatment consisted of the following elements (Supporting Information, S2.2): well water handling, condensate separation and treatment, acid gas removal by amine treatment, dehydration, dewpointing and LPG fractionation, export compression, sulfur recovery, flare stack, and fugitive emissions.

Fugitive emissions were calculated using the facility-level factors from the 2009 API Compendium:[11] 0.17% of the gas is lost to fugitives from onshore production and 0.18% is lost to fugitive emissions from gas processing. (The EPA 2011 Inventory Report[8] estimated that total methane emissions from the natural gas industry were 10 535 kilotonnes in 2009, of which gas processing accounted for 8%, or roughly 0.21% of total gas production, which is in good agreement with the API value.)

The emissions allocated to sales gas in this process amount to 4.18 gCO_2e/MJ, of which 34% is fugitive methane emissions.

Transmission Pipeline. It was assumed that gas was transported 900 miles (1440 km) from gas field to power plant, as used in a recent NETL study of the emissions intensity of Natural Gas Combined Cycle (NGCC) powergen.[12] Based on EIA data[13] it was calculated that 1.4% of the gas is consumed as fuel for the compressor stations (Supporting Information, S2.3).

Fugitive emissions were calculated using facility-level factors for transmission pipelines from the 2009 API Compendium:[11] 0.066% of the gas is lost to fugitive emissions over 900 miles. The emissions intensity of pipeline transmission is then 1.94 gCO_2e/MJ. (The EPA's 2011 Inventory Report[8] estimated that total methane emissions from the natural gas industry were 10 535 kilotonnes in 2009, of which transmission and storage accounted for 20%, or roughly 0.52% of total gas production. If this figure were used, the emissions intensity of pipeline transmission would rise to 3.99 gCO_2e/MJ.)

Power Station. It was assumed that natural gas is burned in the average U.S. power station. Jaramillo[6] quoted 2003 U.S. EIA data which showed natural gas power plant efficiencies ranging from 28% to 58%. The average efficiency (total power/total fuel) was 38.7%.[14]

EIA data[15] show that by 2009 (the last complete year for which data are available) natural gas generating capacity had increased by 41% and the average efficiency increased to 43.0%. By contrast, coal generating capacity fell by 11% over the same period and its efficiency remained almost constant: 33.1% in 2003 and 32.8% in 2009. The emissions intensity of gas powergen has improved relative to coal since Jaramillo's paper appeared (Supporting Information, S2.4).

For Life Cycle Assessment, emissions are conventionally reported per MJ of lower heating value (LHV). For the model, the efficiency of powergen was assumed to be 43.0%, or 47.6% on an LHV basis: 2.10 MJ of gas is needed to generate 1 MJ of electricity. The emissions intensity of the power station is then 122 gCO_2e/MJ or 440 gCO_2e/kWh.

Well-to-Wire Totals: Common Elements. The total WtW emissions (excluding well head operations) amount to 485.2 gCO_2e/kWh. This value is in good agreement with data for gas powergen published by Jaramillo[6] and NETL[12] (Supporting Information, S2.5) and therefore offers a reasonable baseline for comparison of the remaining elements of conventional and unconventional gas production.

RESULTS: CONVENTIONAL GAS

Production Profile. Both conventional and shale gas wells start from a high initial flow rate, which declines over time. Production from a field is maintained by drilling new wells. Real wells exhibit a wide variation in behavior, so a simplified approach was needed. For this analysis, it was only necessary to calculate the emissions intensity per unit of gas; the time profile is unimportant. The well drilling and completion emissions were divided by the estimated ultimate recovery (EUR).

The same EUR value of 2.0 Bcf was used for both conventional and shale gas so the results would show the relative contribution of the different production methods without distortions due to differences in well productivity. The effect of changing this assumption was addressed in the sensitivity analysis.

Well Drilling. The reference case assumed an annual average production 750 mmscf/d (21.1 Msm^3/d) from 500 wells and, following the simplified model above, 137 wells must be drilled each year to maintain production at this level. It was assumed that no fracturing was required. Estimates of methane releases during well completion range from the EPA/GRI factor of 0.71 tCH_4 per completion (based on 1992 data[16]) to the API Compendium onshore well factor of 25.9 tCH_4 per completion-day[11] (based on EIA data from 2000). Allowing two days for conventional well completion, methane emissions would be 0.20% of lifetime production.

Well Completion Emissions Abatement. In an exploration situation, there may be no opportunity to recover methane releases for sale. In these circumstances, methane releases are usually flared (although new opportunities may become available using micro-LNG or electric powergen systems). In a production situation, where a gas pipeline exists, it is technically possible to recover methane releases. For example, Williams Inc.[17] estimated 91% recovery at Picecance basin.

In 2010, the EPA estimated that that 51% of well completion/workover emissions were flared or recovered.[9] Flaring of completions and workovers is required in Wyoming; however, it is not required in Texas, New Mexico, or Oklahoma. EPA assumed no completions were flared in those states and then took the ratio of unconventional wells in Wyoming to the unconventional wells in all four states to estimate the percentage of well completions and workovers that are flared. EPA assumed that this sample was indicative of the rest of the U.S. For the generic conventional gas base case, it was therefore assumed that 51% of the gas used for powergen originates from wells where completion emissions were flared and the rest vented.

Production Emissions Intensity. For the conventional gas base case, diesel used for well drilling added 0.30 gCO_2e/MJ to the common elements. Methane releases from well completion would add another 0.01−0.65 gCO_2e/MJ if vented. If flared at a typical efficiency of 98%, methane release would add only 0.001−0.08 gCO_2e/MJ.

Allowing for an average 51% flaring of methane released in well completion, the model gives an emissions intensity ranging from 4.49 to 4.84 gCO_2e/MJ, of which 31−36% is fugitive methane emissions from well completion and gas treatment.

It is common in the industry to express the intensity of production as the total direct emissions divided by total hydrocarbon production, without allocation to individual products. On this basis, the emissions intensity of conventional hydrocarbon production ranges from 0.211 to 0.228 tCO_2e/tHC (where HC = gas, condensate, and LPG).

WtW Emissions Intensity. The WtW emissions intensity of the conventional base case ranges from 487.5 to 490.2 gCO_2e/kWh, of which 2.7−3.2% is methane. Combustion at the power station makes up 89.5% of the total, pipeline transport 3.0%, common elements 6.5%, and well drilling and completion 1.0%. Well drilling makes up a relatively small part of the WtW emissions in this conventional gas model.

■ RESULTS: SHALE GAS

Production Profile. A survey of unconventional wells (Supporting Information, S4.1) shows that unconventional wells commonly show a steep decline in production, so that the estimated ultimate recovery (EUR) is typically about 3 years but can be as little as 1 year. A Shell internal rule of thumb for shale gas is that EUR is 1200−1500 times the initial production (IP) per day. Data from U.S. Geological Survey indicate that an ultimate recovery of 2 Bcf per well is typical of horizontal shale gas wells.[18] An initial production rate of 1.5 mmscf/d was considered typical for wells of this size.

Well Drilling. The reference case assumed an annual average production of 750 mmscf/d (21.1 Msm^3/d) from 500 wells and that 137 wells must be drilled each year to maintain production. The scatter on Shell's correlation suggests that the ultimate recovery could vary between 1 and 3 Bcf, or 91−273 wells per year, and USGS data show a similar spread.

It was assumed that methane releases were equal to the new EPA factor of 177 tCH_4 per well completion.[9] The EPA completion factor is an average value used for inventory calculations and is independent of well size. These estimates have been challenged as "dramatically" overstated and "not credible" by IHS CERA[19] and ongoing data collection exercises by EPA and API may result in revised values in future. Nevertheless, it is interesting to see what effect methane releases of this scale might have. The factor 177 tCH_4 corresponds to 7 days flowback at the assumed initial production rate of 1.5 mmscf/d and 85% methane content. The API factor of 25.9 tCH_4/completion-day would result in emissions of 181.3 tCH_4/completion over 7 days—not dissimilar to the EPA's estimate. Methane emissions on this scale would amount to 0.46% of lifetime production in the base case (2 Bcf recovery) and 0.92% for the low ultimate recovery case (1 Bcf).

Well Fracturing. It was assumed that the well is fractured immediately after drilling and thereafter no further fracturing is conducted. It was assumed that a total of 15 fracturing operations are needed per well, each requiring 2 h of water injection at maximum pressure. (Approximately 3−5 fracturing operations are conducted each day, allowing for turnaround time between operations). Fracturing fluid was assumed to flow at 50 bbl/min at 10 000 psi (8 m^3/min and 689 bar) corresponding to a "hydraulic horsepower" of 12 250 HP.

Fracturing Water. NETL quotes a range of 2−4 million gallons of water needed to fracture each well.[3] Water for fracturing may be obtained from various sources. In order of increasing cost they are as follows: pipeline from local river (may need holding ponds to cover periods of low flow); drilling for water from nearby aquifer; use of waste ("gray") water from cities; and trucking of water by road tanker.

New York State's Supplemental Generic Environmental Impact Statement (SGEIS) for potential natural gas drilling activities in the Marcellus Shale formation estimated that haulage of all materials (including water) for hydraulic fracturing totaled 15 740−23 040 truck-miles for a one-well project[20] and about 20% less per well for a 10-well pad. At 5 mpg, this is equivalent to 3148−4608 gallons of diesel. For this analysis, the figure was rounded up to 5000 gallons.

Flowback Water Treatment. Typically, 30−70% of the water used will flow back in the days following the fracturing operation.[3] Of this volume, some can be recovered for reuse and the rest is sent for water treatment. For this analysis it was assumed that 4 million gallons of water are used per well, of which 50% flows back and is sent for treatment. Treatment was assumed to consist of trucking of water for disposal a round trip distance of 150 miles by road at 100 bbl load per truck at a fuel economy of 5 miles per gallon of diesel and treatment by a relatively energy intensive method: reverse osmosis and evaporation or freeze−thaw evaporation at 2 kWh/bbl.[21]

Total emissions from one fracturing operation are therefore of the order of 228 tCO_2e, made up of 15 000 gallons of diesel for trucking, and 100 MWh of electricity for water treatment.

Table 1. Shale Gas Operations: Summary of Sensitivity Cases

parameter	low emissions	base case	high emissions
ultimate recovery	3 Bcf	2 Bcf	1 Bcf
produced water	WGR = 0.1	WGR = 0.4	WGR = 0.8
completion/workover emissions	51.8 tCH_4 (API)	177 tCH_4 (EPA)	385 tCH_4 (EPA)
methane emissions abatement	98%	51%	0%
Wellhead pressure	60 bar	40 bar	20 bar
flowback water for treatment	1 million gal	2 million gal	4 million gal
number of fractures per well	10 per well	15 per well	24 per well + workover

Production Emissions Intensity. Shale gas drilling adds 0.44 gCO_2e/MJ to the common elements (more than conventional gas because of the need for hydraulic fracturing). Sourcing and treatment of fracturing water adds another 0.17 gCO_2e/MJ. Methane releases during completion are higher than for conventional wells and would add another 2.26 gCO_2e/MJ if vented. If flared at a typical efficiency of 98%, methane release would add only 0.29 gCO_2e/MJ.

Added to the common elements of 4.18 gCO_2e/MJ, the emissions allocated to shale gas range from 5.08 to 7.05 gCO_2e/MJ. Allowing for 51% flaring of methane released in well completion, the model gives an emissions intensity for shale gas of 6.02 gCO_2e/MJ, of which 54% is fugitive methane emissions from well completion and gas treatment.

The intensity of production expressed as the total emissions divided by total hydrocarbon production (i.e., without allocation) was 0.280 tCO_2e/tHC.

WtW Emissions Intensity. The WtW emissions intensity of the shale gas base case is 499.2 gCO_2e/kWh (1.8−2.4% higher than the conventional gas base cases), of which 4.3% is methane. Although well drilling, fracturing, wastewater disposal, and fugitive emissions have a significant impact on the emissions intensity of production, their effect on WtW emissions is relatively small because the total is dominated by emissions from the power station, pipeline, and common elements. Only 2.8% of the total is made up of wellhead operations upstream of the common elements.

The largest unknown is the amount of fugitive emissions, but even if none of the methane releases from well completion were flared, the WtW emissions would be only 507.4 gCO_2e/kWh, which is 3.5−4.0% higher than conventional gas powergen.

RESULTS: SENSITIVITY ANALYSIS

The model considered a set of parameters representing generic conventional and shale gas production. It was seen that shale gas production has higher emissions, but that these emissions do not add significantly to the WtW emissions intensity of powergen. However, future conventional and shale gas production might depart significantly from these initial assumptions, so a sensitivity analysis was conducted.

Shale Gas Operations. To describe more or less difficult unconventional gas production, the following parameters were varied above and below the base case:

- Ultimate recovery: the more gas is recovered from a well, the smaller the contribution of well drilling and fracturing to the emissions intensity per unit of gas produced. A range of 1−3 Bcf was explored.
- Produced water treatment: a water−gas ratio of 0.8 represents a doubling of the base case, included for interest. In fact, shale gas is relatively dry shale and the lower value of WGR = 0.1 is a more likely scenario (see Supporting Information). Water treatment (desalination) was assumed to require 0.5 kWh/bbl.[21]
- Well completion emissions: the EPA's estimated emissions ranged from 13 to 385 tCH_4 per completion or workover[9] (16 rather than 7 days flowback time). The API value of 51.8 tCH_4 used for the conventional gas base case was taken as the lower bound.
- Completion/workover emissions abatement: in the worst case, methane is vented; in the best case, flaring is typically 98% efficient.
- Wellhead pressure: wellhead pressure could fall quickly after initial production and compression would then be needed in the gathering system.
- Flowback water: it was assumed that this might vary from half to twice as much as the base case.
- Fractures per well: A report from the Tyndall Centre described a scenario in which wells were refractured once and outputs from these are 25% higher than unfractured wells.[22] There will be a second methane release equal to the original completion emissions. This is equivalent to 1.6 times as much fracturing per unit of gas produced, or 24 fractures per well rather than 15.

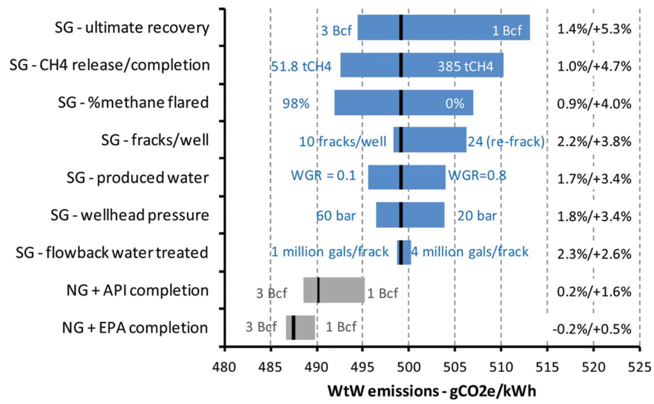

Figure 2. Tornado plot. Sensitivity of WtW emissions intensity to best/worst parameter settings changed one at a time about a 2 Bcf base case.

Conventional Gas Operations. The ultimate recovery of the conventional gas base case was also varied from 1 to 3 Bcf, for both EPA and API methane release factors for well completion.

A summary of the parameters varied is given in Table 1. The results of these sensitivity cases on WtW emissions are shown as a tornado plot in Figure 2 below.

Although large changes in production emissions are seen, the changes in WtW emissions are not as large because production emissions make up only a small part of the total. In Figure 2, each

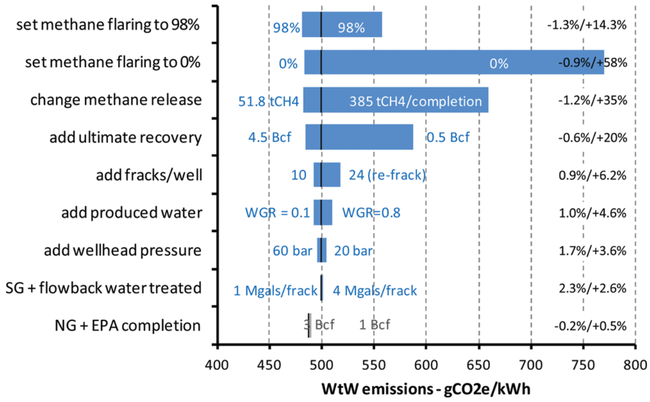

Figure 3. "Worst case" plot. Cumulative effect of best/worst parameter settings on top of a 2 Bcf base case.

gridline represents a 1% change in WtW emissions intensity. The following factors can increase emissions by more than 1% above the base case:

- Ultimate recovery: determines the number of wells drilled per unit of gas. This affects both the amount of diesel used for drilling and the fugitive emissions per well.
- The amount of fugitive emissions per well completion: high methane releases obviously increase the WtW emissions.
- If the fugitive emissions of well workovers and completions are not flared or recovered, then these can also significantly increase WtW emissions.
- The number of fracturing operations carried out per well is relatively unimportant, unless the well is refractured during its life, in which case the fugitives emissions from well workover become significant.

The following factors can increase WtW emissions by less than 1% above the base case:

- Produced water: a high water−gas ratio increases the energy required for water treatment and transport.
- Low wellhead pressure increases the energy needed for compressing the gas between wellhead and gas treatment.
- Treatment of flowback water after fracturing is relatively insignificant. These operations are conducted only once or twice in the life of a well and contribute little per unit of gas produced.

RESULTS: WORST CASE ANALYSIS

In the sensitivity cases explored above, the various parameters were varied one at a time about the base case. In reality, individual producers may be affected by multiple factors, e.g., high initial methane release followed by rapid decline, leading to low ultimate recovery. The following analysis applied the best and worst assumptions cumulatively to derive best and worst cases.

Although an ultimate recovery of 1−3 Bcf was considered suitable to describe generic shale gas, USGS data show that individual wells can have much higher or lower yields. The range was widened to 0.5−4.5 Bcf for this "worst case" analysis. Otherwise, the best and worst parameters from Table 1 were applied unchanged.

The assumptions generate extreme results, as shown in Figure 3. In the best case, shale gas could have WtW emissions slightly lower than the base case. In the worst case, the WtW emissions intensity of shale gas could be nearly 60% higher than conventional gas.

Some emissions abatement would be possible even in the most unfavorable situations. For a given geology and location, little could be done about gas quality, pressure, flow rate, or water production but the following abatement options may still be possible, individually or all together. Methane releases could be reduced with better working practices and equipment. Flaring or recovery of well completion/workover emissions can be put in place, even where it is not mandatory. It may be possible to avoid treatment of produced water by reinjecting it.

Figure 3 also shows the effect of flaring of well completion emissions at 98% efficiency. Even in the most unfavorable case, effective abatement of methane releases could reduce the WtW emissions from shale gas to less than 15% higher than conventional gas. Note that in all cases considered, shale gas has lower WtW emissions than coal powergen, which has approximately twice the WtW emissions of conventional gas powergen.[11]

DISCUSSION

Shale Gas versus Conventional Gas. The findings of the modeling work were that the WtW emissions of shale gas were approximately 1.8−2.4% higher than conventional gas for the base cases considered and that individual producers might have a higher WtW emissions intensity but with efficient flaring of methane releases, WtW emissions need be no more than 15% higher, even in the most unfavorable circumstances modeled.

Two trends are apparent in the model results. First, that the emissions intensity is strongly affected by the ultimate recovery from a well. Second, that methane releases during well completion can significantly increase the emissions intensity of production unless abated through flaring or recovery. It is the methane released rather than the diesel fuel burned which contributes most to GHG emissions from drilling, fracturing, or refracturing of unconventional gas wells.

For the generic conventional gas base case, an ultimate recovery of 2.0 Bcf was assumed. However, for wells in the U.S., EUR has been in decline for many years and a value of 1.0 Bcf might be more realistic (based on EIA[23] and EPA[8] data, as described in Supporting Information, S3.1). By contrast, shale gas production in the U.S. has begun with large productive wells, so that it is possible that the emissions of well drilling and completion are currently lower per unit of shale gas than older, less productive conventional wells. Ultimately, production from shale gas may also decline, reducing the gap again.

The uncertainty around the EPA's latest estimate of methane emissions highlights the need for better understanding. Starting in 2011, the U.S. Greenhouse Gas (GHG) Reporting Program will collect comprehensive actual emissions data from major sources across the United States petroleum and natural gas industry. Using these data, the EPA will be able to refine their emissions factors in future inventory calculations.

Natural Gas versus Coal Powergen. Studies by NETL compared new-build gas[24] with existing and new-build coal powergen[25,26] in the U.S. NETL's results showed that the WtW emissions of conventional gas powergen are 53−58% lower than coal, when new-build gas powergen is compared against existing or new-build coal powergen. The higher production emissions of shale gas production amount to only a few percent over the WtW life cycle and do not close the gap between gas and coal by any significant amount.

Comparison with Other Studies. The modeling study predicted that development and completion of a shale gas well results in production emissions 1.2−1.5 gCO_2e/MJ higher than conventional gas and that WtW emissions were 1.8−2.4% higher over the life cycle of gas powergen. It is interesting to compare these findings with other, recently published results.

IEA recently estimated[27] that ″...total emissions from shale gas from production through to use (well-to-burner) are only 3.5% higher in the best case (flaring the gas) than the equivalent figure for conventional gas, and about 12% higher in the worst case (venting the gas)."

A study of Marcellus shale gas by Carnegie Mellon University[28] concluded that ″...development and completion of a typical Marcellus shale well results in roughly ...1.8 gCO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents ... a 3% increase relative to the life cycle emissions when combustion is included.″

The Tyndall Institute[22] evaluated shale gas emissions in the context of production in the United Kingdom and concluded that ″...the additional emissions from the shale gas extraction processes identified represent only 0.2−2.9% of combustion."

There is broad agreement among the studies, despite the differences in approach and assumptions. A significant outlier is a publication by Howarth et al.[29] which concluded that, "Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years." The apparent contradiction can be traced to significant differences in the underlying data and methodology. First, methane releases were overestimated: evidence for flaring and recovery was disregarded in their estimate of flowback emissions;[17,30,31] "venting and flaring" was interpreted to mean 100% vented;[32] lost and unaccounted for gas (LUG) in pipelines (mostly used as fuel) was mistakenly assumed to be lost to leaks;[33] and finally, lost gas was assumed to be 100% methane. Second, the difference between coal and shale gas was increased by the following: use of 20-year rather than the accepted 100-year basis for global warming potential, use of non-IPCC factors for global warming potential, and by failing to account for differences in power station efficiency. Applying 2007 IPCC AR4 GWP factors, 32.8% coal and 43.0% gas powergen HHV efficiency, and assuming 51% flaring of methane, Howarth's worst case of 7.9% methane leakage translates into shale gas emissions ∼30% lower than coal (not dissimilar to the worst case in Figure 3) and if average methane emissions are assumed to be 2.6% (in line with the EPA inventory report for 2009[8]), then gas has half the WtW emissions of coal, in line with the consensus view of Jaramillo,[6] CMU,[28] and NETL[12] (Supporting Information, S7).

In conclusion, this modeling study shows that emissions from shale gas are not as high as some alarmist articles have claimed and that, so long as control or abatement of methane emissions are in place, shale gas WtW emissions are comparable with conventional gas and significantly lower than coal when used for powergen.

ASSOCIATED CONTENT

Supporting Information. Details of the parameters used in the model and additional figures. This material is available free of charge via the Internet at http://pubs.acs.org

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